Hydraulic Jet Pumps Prove Ideally Suited for Remote Canadian Oil Field

Abstract
With 150 Million Barrels of recoverable reserves, the Nexen Hay River Bluesky oil pool is among the largest oil discoveries in Western Canada in the past two decades. Initial pilot production testing led to the conclusions that, in order to produce the field in its most economical fashion, the following would be needed:

- Triple lateral horizontal producing wells
- In field horizontal water injection/water disposal wells for pressure maintenance
- Artificial Lift from the outset

Further complicating production of the Hay Pool, which is located in a remote area of North-Eastern British Columbia, was the fact that road access would be limited to 4 months of the year because any road through the muskeg would need to be “frozen in” prior to use. It was therefore extremely important to the economic viability of the project that whatever means of artificial lift were chosen should be highly reliable and require minimal maintenance. The method chosen, apart from being reliable and safe, would also need to be capable of lifting large volumes of fluid with a significant pressure drawdown. In addition it would need to be able to operate successfully in the extreme well deviations common in the “build” sections of the development wells.

This paper will review the development of the Bluesky oil pool and present the case for the choice of Jet Pumps for artificial lift. The authors will go on to detail the performance of the Jet Pump system installed in the field that has met or exceeded all performance expectations.

Background
The Hay development project exploits a medium to heavy oil (24° API) reservoir located about 40 miles northwest of Rainbow Lake in northeast British Columbia near the Alberta border (Figure 1). The productive formation is the Lower Cretaceous Bluesky sand encountered at a true vertical depth of about 1,060 ft. The Bluesky is an offshore to lower shore-face sandstone deposited in an overall transgressive marine environment. Porosity values range from 18-27% and permeability values range from 60–250 md. The oil zone, which is 13-15 feet thick, is underlain by an 18-foot water zone and overlain by 560 – 885 ft of Buckinghorse shale followed by glacial deposits.

Figure 1. Area Map Of Hay Project Location

The field is located under a very flat muskeg area that is accessible only during the winter months of the year. Drilling locations are prepared when the surface is frozen and ice roads can be used, typically from mid-December to mid-March, but at all other times of the year they are only accessible by helicopter or hovercraft.

The field was discovered in 1984 and after drilling several vertical wells it was found that the thin reservoir and its close proximity to bottom water made production from vertical wells uneconomical. A horizontal well was drilled in 1995 to evaluate their potential to produce at adequate oil rates with reduced water cuts. Although this well encountered numerous drilling difficulties and was not considered economical due to the high drilling costs, it did test oil with a reduced water cut of 20%.
Pilot Production Tests

A pilot project was initiated in 1998 to further evaluate the potential for producing oil using horizontal well technology. Firstly, the sole existing horizontal well from 1995 was worked over and after cleanout of the lateral section with a jetting tool and the re-installation of the progressive cavity pump at a greater TVD the well production increased appreciably. One important lesson learned from the horizontal well workover was the fact that well control was a key concern, as it took three days to kill the well. Secondly, four well workover was the fact that well control was a key concern, as it took three days to kill the well. Secondly, four single leg horizontal wells were drilled to an average lateral length of 3,825 ft. (Figure 2). These wells demonstrated the feasibility of drilling relatively long laterals in the thin sand and proved that the formation was competent enough to produce the wells with open-hole completions. Once drilled, the wells were suspended with a bridge plug in the intermediate casing until a service rig could move on to complete the well. During the completion phase, well control was a major factor, with more time being spent in killing the well than in running the actual completion. The wells were equipped with PCP’s landed in a tangent section of the wellbore and a variety of rod accessories (scrapers, spin through couplings etc.) were employed in an attempt to determine what configuration (if any) would work best in directional wells with such aggressive build rates and stringent drawdown requirements. Production tests from these wells confirmed the potential for economic recovery with an average fluid rate of 315 bbls/day with a 13% water cut. The production potential was actually understated as the PCP’s used were undersized and incapable of achieving the drawdown necessary to maximize production. The production tests were limited to one month and, although none of the artificial lift systems failed, any appraisal of the long term durability of a given rod / pump configuration was inconclusive.

Production Considerations

While drilling operations could be planned and conducted in a finite time frame as dictated by the restrictions in access to the project location, it was clear that production operations would have to be considered differently. Well completions and the installation of surface facilities could be done in parallel with the drilling season but the day-to-day operations associated with production presented a different challenge. It was clear that a production system that could operate reliably, while essentially unattended, would be critical to the financial success of the project. Since it was determined that both artificial lift and water injection would be required from the outset, the choice of artificial lift mechanism was the subject of a great deal of research within both the participating partners and the industry in general. Many variables would have to be taken into account, such as fluid handling requirements, surface facility dimensions, power generation requirements, equipment reliability and, perhaps most significantly, workover frequency. Several different mechanisms were considered as follows:

- **Electric Submersible Pumps (ESP)** – Whilst an established and highly reliable artificial lift mechanism, the ESP could not be landed far enough downhole to achieve maximum drawdown, due to the severity of the dog legs (15°/100 ft). Sizing of the ESP, potential problems handling gas production, field electrification requirements and possible workover requirements eliminated the ESP from consideration, at least for the initial year of development.

- **Progressive Cavity Pumps (PCP or Screw Pump)** – this is a system that is widely used in Canada and has an established performance track record in existing operations. Among the advantages that it offers are low power requirements, the fact that the surface plant design requirements could be kept small (lower fluid handling requirements) and the belief, based on field experience, that a 3 year run life was achievable, thereby minimizing workover requirements.

- **Gas Lift** – the simplicity of the downhole completion, requiring only gas lift valves is very attractive and would have been ideal for employment at Hay. However, after review of gas lift program results it was concluded that sufficient pressure drawdown could not be obtained with gas lift.

- **Jet Pumps** - this system, which was in limited use in Canada at the time, uses the transfer of energy from power fluid (such as water or produced crude oil) pumped into the tubing at high pressure to lift formation fluid up the annulus. Among the advantages it offers is low maintenance costs, ease of pump change-out and a centralized surface equipment package, however a major disadvantage is the power requirements which, due to its method of energy transfer, are almost double those needed for the PCP.

The project team made the initial decision that the field would be developed utilizing PCPs, although there was still
genuine concern that any rod pumping system would be hard pressed to provide adequate run time in such a remote area.

**Initial Jet Pump Pilot Test**

No additional wells were drilled the following year due to a combination of low oil prices and a need to wait for royalty reform, but two of the previously drilled horizontals were put on an extended production test from January to March. One single leg horizontal well was equipped with a High Volume Progressive Cavity Pump (PCP) and another single leg horizontal well was equipped with a Hydraulic Jet Pump. The workover operations to install the pumps were extremely costly due to difficulties with well control, one well taking 7 days to kill. Although the wells would flow readily under initial reservoir conditions, artificial lift would be required to draw the wells down far enough to achieve the desired production rates.

The pilot production test confirmed the potential for commercial production and also demonstrated that the jet pump could produce equivalent volumes to that of a PCP. The PCP well was equipped with a Promore Downhole Sensor in order to obtain Real Time Bottom Hole Producing Pressure. In order to achieve the drawdown required to maximize production, the pump was located in a tangent section of the hole at approximately 68 degrees inclination. The rod string above the pump was equipped with spin through couplings to minimize wear in the build section, which had dog leg severities in the range of 13 degrees/100 feet. A tubing rotator, swivel and no-turn tool were also run. The pump positioning and rod design was dual purpose; to provide the required drawdown and to give the PCP an intentional “torture test.” If the field was to be developed with PCP’s, it was estimated that a 3-year service life under these extremely difficult conditions would be required. The Jet Pump was landed at an equivalent depth, inclination and dogleg severity. A schematic of the pilot testing artificial lift systems is shown in Figure 3.

The surface equipment (triplex pump, prime mover, separator etc.) used for the jet pump installation was what was readily available in the field rather than equipment ideally suited for the trial application. Problems with cavitation in the power fluid system and separation of the produced fluids contributed to the step rate type performance. Nozzle selection and system horsepower versus bottom hole pressure drawdown is always a compromise, however in this pilot test the bottom hole producing pressures of both the PCP well and the Jet Pump well were nearly identical. The Pilot Production Test results are shown in Figure 4.
Despite the performance of the jet pump there remained considerable apprehension about using the system exclusively and it was decided to use PCP’s on two pads and jet pumps on one pad for the first year of the development program.

**Final Artificial Lift Selection**

Upon further review of all aspects of the project, the choice of artificial lift medium was revisited and the primary considerations for the success of the project were reconsidered in detail. The conclusion was reached that the economic risks of the Hay Project Risk were now related to operations and production, rather than geology and exploration and that the aspect of the operation that was of paramount concern was reliability rather than efficiency, it being essential that production be maintained in the “non-drilling season”. Subsequent to the evaluation of the pilot production test and simulation, a major change in the depletion strategy of the reservoir was made. Rather than proceeding with produced water injection peripherally to the producing oil pool boundary, the lack of aquifer support necessitated that pressure maintenance by in-field water injection would be required with the same tight spacing pattern as the producing wells. This meant that water injection lines would need to run to the producing pads where there would typically be four triple lateral horizontal producers and four injectors per pad, two dual leg horizontal injectors and two single leg horizontal injectors (Figure. 5).

![Figure 5. Production and Injection Well Pattern](image)

Since a source of power fluid was coming to the pad anyway, the only additional cost of running the jet pump would be the incremental horsepower needed to boost the pressure of the entire water system and supply the required volume to the jet pump using larger lines as needed. This could facilitate the complete field being produced and pressure maintained by simply pumping fluid from the central facility to the producing pads with a minimal electrical distribution system being required in the field. Costs were estimated for full field development based on production of 6000 bbls/day of oil and 120,000 bbls/day of water. Even though the jet pump option had a considerably higher horsepower requirement, when all costs were considered especially those associated with workover and lost production, it was decided to change the allocation of pump types and equip one pad with PCPs and two with Jet Pumps. Operations proceeded accordingly during the 2000-drilling season with the following installations being made:

- One pad with 6 wells was completed with PCP, with the pumps being landed in the build section. In order to achieve the required drawdown of some 50%, the rotational requirements were 300rpm.
- Two pads, a total of 8 wells, were equipped with Jet Pumps with the pump being landed 10-20 meters above the formation in the 70˚ build section.

The results of the first year of production proved conclusively that the Jet Pump was far and away the best choice for the project. Once the drilling season was over and summer conditions prevented access except on a very limited basis, the Screw Pumps all failed and downtime was considerable with commensurately high workover costs. Rod jobs were performed on the wells using a mast unit mobilized to the location by helicopter, however it was not possible to pull tubing until full access for a workover unit could be regained in the drilling season. The wells were worked over the following winter season and the pumps were placed up in the vertical section of the wells but, though performance did show improvement, most of the Screw Pumps failed again.

By contrast there was no downtime due to failure of the Jet Pumps and production was maintained from these 8 wells throughout the year. A comparison of the downtime hours by failure type is shown in Figure. 6.

![Figure 6. Downtime Hours By Failure Type](image)

Several issues did arise which hindered operations and would need to be addressed, such as the presence of scale inhibiting the ability to circulate the pumps out of the well and problems with emulsion at the facilities. It was also determined that the wells must be drilled within the sand interval as wells drilled into the shale cap were susceptible to hole collapse. However the first full year of production proved conclusively that the jet
pump approach was by far the most viable with the resultant decision that all new wells would be completed, and all existing PCP installations worked and recompleted, with them. Production data illustrating the comparison of the run life performance of both types of pump during the first year of production is contained in Figure. 7.

![Figure 7. Typical PCP and Jet Pump Production Performance](image)

### Additional Jet Pump Advances and Advantages

The jet pump completions allowed for the use of the same tubulars and packer as the injection well completions, making for simplified completion operations. As mentioned earlier in this paper, well control was of paramount concern at Hay and it was absolutely critical that the completion be run in the hole as soon as possible after the completion of drilling. For this reason the well completions were performed by the drilling rig immediately following the drilling operation. With the tubing head having been already installed when intermediate casing was set, the packer and tubing (and jet pump bottom hole assembly on the producers) were run in the well and the tubing landed. A double box bushing tubing hangar was used in conjunction with a Back Pressure Valve in order to ensure that at no time there was any exposure to well flow, in addition to facilitating reliable setting of the retrievable packer at such shallow depths. The jet pump completions performed by the drilling rig were simpler, cheaper, faster, and safer, than other completion alternatives.

Nexen had a jet pump recorder housing built which allowed the bottom hole producing pressure on any producing well to be determined by simply circulating the pump in the well, producing for a defined period, and circulating the pump and pressure recorder back out of the hole. Some wells were equipped with permanent sensors with surface read out however the jet pump recorder carrier provided additional flexibility in determining bottom hole pressures at a substantial cost savings. Nexen also designed a simple 4-way valve system and wellhead, which made for fail-safe operation of the pumps and greatly reduced wellhead maintenance.

For the water source wells, a jet pump was used in conjunction with a booster pump, to supply greater power fluid pressure, and a second centrifugal pump to both reduce the casing pressure and deliver the produced fluid to the central facility. These wells, equipped with 2 7/8” tubing, were able to produce 5600 BPD when put on initial production.

At the time of the writing of this paper, jet pumps are being used at Hay with the capability of producing either up the casing or the tubing. This type of pump can be configured to produce the well up the casing on original well clean up and then produce up the tubing for long term production in potentially corrosive environments. The project has also proved to be larger than originally anticipated with current production of 9000 bbls/day of oil and 230,000 bbls/day of water.

### The Jet Pump

![Figure 8. Jet Pump](image)

A typical jet pump is illustrated in Figure 8, it is landed in a pump seat located in the tubing string close to the casing shoe and is activated by pumping high pressure power fluid (in this case produced water) down the tubing. The power fluid enters the pump at the nozzle where a transfer of energy occurs to the produced fluid entering the pump throat from below. The combined fluid is discharged into the tubing/casing annulus above the packer and thence to the surface where it is separated in the production facilities and the water used for both power fluid and water injection requirements - a typical surface facility and flow path is shown in Figure 9.
In this particular application the Jet Pump offers several major advantages:

- It has no moving parts so it is very reliable and has low maintenance requirements. Only abrasion and wear of the nozzle and throat area is of concern and this can be addressed by appropriate material choice.
- It is very easy to change out in the event of wear, either by reverse circulating it to surface or retrieving it on wireline.
- It can pump high fluid volumes.
- It can be run in severe build sections and can thus be placed very close to the formation to facilitate maximum drawdown.
- It allows for localization of power sources into one facility.

By the same token the jet pump has several disadvantages that can make it unsuitable for some production operations, among these are:

- It has lower efficiencies when compared to other pump systems, requiring considerably more horsepower.
- The high volume of fluids it requires for activation mandate the need for large surface facilities with consequent higher capital costs.
- It is very dependent upon backpressure.

Conclusions

While the Jet Pump may not be suitable for some applications, in the case of the Hay project it was ideally suited due to its reliability, low down time and minimal maintenance requirements. All 77 producing wells are now equipped with jet pumps and plans are currently being implemented to equip an additional 17 wells in the 2003/2004 drilling season. It is recommended that the Jet Pump should be considered for all field applications where its attributes address the paramount development requirements and especially for those where high volume lift is an absolute necessity. Detailed up-front planning is a must to ensure that facilities are capable of handling the fluids for both power fluids and injection requirements, as utilizing existing injection line networks can be a major contributor to a projects’ economic viability.

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References


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